REMARKS

Claims 1-21 remain pending. Claims 1-21 were rejected. Applicants have amended Claim 1 herein. Reconsideration of the application is respectfully requested. Applicants seek allowance of the pending claims based on the following:

I. AMENDMENT

In the Claims:

Please amend the claims as follows:

1. A method of calculating a static formation temperature in a reservoir penetrated by a wellbore; comprising:

 estimating the static formation temperature;

 calculating a formation fluid temperature at the wellbore using a three-dimensional fluid flow model through the reservoir, said calculation based, at least in part, on the estimated static formation temperature;

 measuring the temperature of a sample of formation fluid at the wellbore;

 comparing the calculated formation fluid temperature at the wellbore with the measured temperature of the sample of formation fluid; and

 predicting the static formation temperature by altering the estimate of the static formation temperature until an error between the calculated formation fluid temperature at the wellbore and the measured formation fluid temperature is minimized.

II. RESPONSE TO OFFICE ACTION

A. Drawings

Applicants note with appreciation that the proposed substitute sheets of drawings filed on February 13, 2002 have been approved. The Examiner indicated that proper drawing correction or corrected drawings are required in reply to this Office Action. In response to this request, Applicants submit herewith a copy of the formal drawings as filed with the Official Draftsman on February 13, 2002 (certificate of mailing dated January 22, 2002).

B. Copy of Papers Originally Filed

The Examiner indicated that documents filed on February 13, 2002 (certificate of mailing dated January 22, 2002) have not been made part of the permanent records of the USPTO for this application because of damage from the US Postal Service irradiation process. The documents filed on February 13, 2002 (certificate of mailing dated January 22, 2002) include the following "Documents:"

1. Transmittal Letter with Certificate of Mailing dated January 22, 2002;
2. Formal Drawings (5 pages); and
3. Return Receipt card.

Applicant provides herewith a true and accurate copy of these Documents as filed, together with the following statement in support of these Documents:

> Applicants verify that the Documents attached hereto are a complete and accurate copy of the documents originally submitted on February 13, 2002 (certificate of mailing dated January 22, 2002).

Applicants submit these Documents within three months of the mail date of this Office Action, namely by March 18, 2003, for replacement of the originally filed Documents to be used as the permanent Office record of the Documents.

Applicants note that an additional set of documents were filed by Applicant on January 22, 2002, but were stamped by the USTPO as received on February 8, 2002. Applicants assume that the copies of these papers stamped February 8, 2002 were not damaged and have, therefore, not provide copies of the February 8, 2002 documents.

C. Information Disclosure Statement

Applicants note with appreciation that the information disclosure statement filed November 30, 2001 has been placed of record and the references cited therein have been considered.

D. Claim Rejections – 35 USC § 102

The Examiner rejected claims 1, 2 and 9-11, and 16 under 35 U.S.C. § 102(b) as being anticipated by Coblentz et al." ("*Coblentz*") or Curtis ("*Curtis*"). In support of the rejection, the Examiner stated the following:

> 5. Claims 1 and 9-11 are rejected under 35 U.S.C. 102(b) as being anticipated by Coblentz et al. [hereinafter Coblentz].
>
> Coblentz discloses a method of calculating a static formation temperature in a reservoir penetrated by a wellbore, comprising: estimating the static formation temperature [Te]: calculating a formation fluid temperature at the wellbore [Tf], said calculation based, in part, on the estimated static formation temperature (see line 5 through 64 of column 5); measuring the temperature of a sample of formation fluid at the wellbore [T] (see lines 13-15 of column 6); comparing the calculated formation fluid temperature at the wellbore with the measured temperature of the formation fluid; and predicting the static formation temperature by altering the estimate of the formation fluid temperature until an error between the calculated formation fluid temperature at the wellbore and the measured formation fluid temperature is minimized (see lines 29-55 of column 2).

Said method further comprises inserting a sink probe [30] engaging the sink probe with the formation at a wellbore wall through perforations [15, 18], and removing fluid from the formation at the wellbore by the sink probe through perforation [15, 18] at substantially known withdrawal rate due to the use of a fluid flow sonde [36] in the sink probe. Said sink probe]30] is run into the wellbore on a wireline/tubular string [31].

6. Claims 1, 2, 9-16 are rejected under 35 U.S.C. 102 (b) as being anticipated by Curtis.

Curtis discloses a method of calculating a static formation temperature in a reservoir penetrated by a wellbore, comprising: estimating the static formation temperature [TEMP(DG)]: calculating a formation fluid temperature at the wellbore [TEMP (DE)], said calculation based in part, on the estimated static formation temperature (see lines 57-68 of column 11); measuring the temperature of a sample of formation fluid at the wellbore; comparing the calculated formation fluid temperature at the wellbore with the measured temperature of the formation fluid (see lines 15-22 of column 25); and predicting the static formation temperature by altering the estimate of the formation fluid temperature until an error between the calculated formation fluid temperature at the wellbore and the measured formation fluid temperature is minimized (see lines 11-22 of column 14, lines 46-68 of column 26 and Figure 5).

Said calculation of formation fluid temperature at the wellbore comprises solving radial heat flux equations (see lines 12-17 of column 30).

Said inserting a sink probe [45] within the wellbore; engaging the sink probe with the formation at the wellbore wall; and removing fluid from the formation at the wellbore through perforations [30] by the sink probe at substantially known rate. Said sink probe is run into the wellbore on a wireline/tubular string [42].

With respect to claims 12-15: Curtis discloses a method of calculating a static formation temperature in a reservoir penetrated by a wellbore [20], comprising: estimating the static formation temperature [TEMP(DG)] in the reservoir and a wellbore fluid temperature [TEMP(DE)]; creating a calculated formation fluid temperature at the wellbore versus time profile for fluid removed from the formation by a sink probe see lines 7-45 of column 7), based upon, in part on the estimates of the static formation temperature in the reservoir and the wellbore fluid temperature; measuring the temperature of the formation fluid at the wellbore removed from the formation by the sink probe (see lines 31-37 of column 14 and lines 46-68 of column 26), and creating a measured fluid formation temperature at the wellbore versus time profile (see lines 7-60 of column 7); comparing the measured fluid formation temperature at the wellbore versus time profile to the calculated formation fluid temperature at the wellbore versus time profile is minimized (see lines 62-68 of column 26 and Figure 5). Said method further comprises inserting a sink probe [45] within the wellbore; engaging the sink probe with a wellbore wall and removing fluid from the formation at the wellbore through perforations [45] by the sink probe at a

> substantially known withdrawal rate. Said sink probe is run into the wellbore on a wireline/tubular string [42].
>
> Curtis further discloses that injection of fluid into the wellbore is deactivated during the disclosed measurement method (see lines 42-45 of column 2) and hence it is considered that the sink probe is run into the wellbore after the wellbore fluid circulation within the wellbore has ceased.

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Applicants' amended claim 1 recites a method of calculating static formation temperature by "estimating the static formation temperature," "calculating a formation fluid temperature at the wellbore <u>using a three-dimensional fluid flow model through the reservoir</u>, said calculation based, at least in part, on the estimated static formation temperature," "measuring the temperature of a sample of formation fluid at the wellbore," "comparing the calculated formation fluid temperature at the wellbore with the measured temperature of the sample of formation fluid;" and "predicting the static formation temperature by altering the estimate of the static formation temperature until an error between the calculated formation fluid temperature at the wellbore and the measured formation fluid temperature is minimized."

Neither *Coblentz* nor *Curtis* teach, *inter alia*, the step of calculating a formation fluid temperature at the wellbore <u>using a three-dimensional fluid flow model through the reservoir</u>, said calculation based, at least in part, on the estimated static formation temperature as recited in Applicants' amended Claim 1 and the claims that depend therefrom. Additionally, Neither *Coblentz* nor *Curtis* teach engaging the sink probe with the formation at a wellbore wall and/or removing fluid from the formation at the wellbore by the sink probe at a substantially known withdrawal rate as recited in Applicants Claim 9 and the claims that depend therefrom. As shown in Figure 1 of *Coblentz* and Figure 1 of *Curtis*, the sonde does not contact the wellbore wall and fluid is not drawn into the sonde (note arrows).

Applicants' Claim 9 recites, *inter alia*, the steps of "creating a calculated formation fluid temperature at the wellbore versus time profile for fluid removed from the formation by a sink probe, based upon, in part on the estimates of the static formation temperature in the reservoir and the wellbore fluid temperature;" and "measuring the temperature of the formation fluid at the wellbore removed from the formation by the sink probe, and creating a measured fluid formation temperature at the wellbore versus time profile."

Curtis teaches a borehole instrument 45 positioned in a wellbore. *See Figure 1*. *Curtis* fails to teach engaging the borehole instrument with the formation at a wellbore wall and/or removing fluid from the formation at the wellbore by the sink probe at a substantially known withdrawal rate as recited in Applicants Claim 12 (and the claims that depend therefrom). As shown in Figure 1 of Curtis, the borehole instrument does not contact the wellbore wall and fluid is not drawn into the sonde (note arrows).

Applicants submit that the Claims meet the requirements of 35 U.S.C. § 102. Applicants, therefore, request withdrawal of the rejection of Claims 1, 2 and 9-16 (and any claims that depend therefrom) under 35 U.S.C. § 102.

E. <u>Claim Rejections – 35 USC § 103</u>

The Examiner rejected claims 3-8 and 17-21 under 35 U.S.C. § 103 "as being unpatentable over Curtis in view of Stewart." In support of the rejection, the Examiner stated the following:

> Curtis discloses a method as recited, as stated above in paragraph 6, but fails to disclose the following limitations:
> - the calculation of formation fluid temperature at the wellbore comprising developing a three-dimensional fluid flow model through the reservoir, as recited in claim 3, wherein the three-dimensional fluid flow model through the reservoir is

developed using an estimate formation fluid withdrawal rate at the wellbore, as recited in claim 4;

- the calculation of formation fluid temperature at the wellbore comprising solving radial heat flux equations in conjunction with a three-dimensional fluid flow model to develop a calculated fluid formation temperature at the wellbore versus time profile, as recited in claim 6, and wherein the error between the measured temperature of a sample of formation fluid at the wellbore versus time profile and the calculated formation fluid temperature at the wellbore versus time profile is quantified, as recited in claim 7, and further wherein the static formation temperature is predicted by minimizing the error between the measured temperature of a sample of formation fluid at the wellbore versus time profile and the calculated formation fluid temperature at the wellbore versus time profile, as recited in claim 8.

Stewart teaches the use of radial heat flux equations in conjunction with a three-dimensional fluid flow model to develop a calculated fluid formation temperature at a volume of the reservoir versus time profile (see abstract lines 42-68 of column 4, lines 3-40 of column 5, lines 23-49 of column 6), said model also taking into account the withdrawal rate (see line 43 of column 21 through line 68 of column 24). Stewart further shows that a measurement is performed on a sample of formation temperature fluid at a given location in said volume in the wellbore and an error between the measured temperature of the sample and the calculated formation fluid temperature at said given location in the volume is quantified (see lines 8-51 of column 19 and lines 1-24 of column 7) and further the error is minimized between the measured temperature of the sample at a given location in the volume and the calculated formation fluid temperature (see lines 20-24 of column 7).

Therefore, it would have been obvious to one of ordinary skill in the art at the time the invention was made to expand the method disclosed by Curtis by adding the step of solving radial heat flux equations and developing a three dimensional fluid flow model in order to calculate the formation fluid temperature at the wellbore, as taught be Stewart, in order to improve the accuracy of the estimated formation temperature.

With respect to claims 17-21: It is considered that the steps recited in said claims, as previously addressed above, will be performed during the method resulting fro the combination of Curtis and Stewart.

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Applicants hereby provide the following statement:

This pending Application serial number 10/006,612 and U.S. Patent 3,913,398 to *Curtis* were, at the time the invention of this Application was made, owned by Schlumberger, the assignee of this Application.

Applicants, therefore, request withdrawal of the 103 rejection based on U.S. Patent 3,913,398 to *Curtis*.

Applicants submit that the none of the cited and/or applicable references teach, disclose and/or suggest the invention as claimed. Applicants further submit that the claims as amended meet the requirements of 35 U.S.C. § 103 and, therefore, request withdrawal of the rejection of Claims 3-8 and 17-21 (and any claims that depend therefrom) under 35 U.S.C. § 103.

III. CONCLUSION

Attached hereto is a marked-up version of the changes made to the claims by the current amendment. The attached pages are captioned "**Version with markings to show changes made.**"

The Applicants believe the claims are in condition for allowance, early passage to issuance is requested. The Examiner is invited to contact the undersigned patent attorney at 281.285.8809 with any questions, comments or suggestions relating to the referenced patent application.

Date: 3/18/03

Respectfully submitted,

J.L. Jennie Salazar
Attorney for Applicants
Reg. No. 45,065

200 Gillingham Lane, MD-9
Sugar Land, TX 77478
281.285.8809

VERSION WITH MARKINGS TO SHOW CHANGES MADE

WHAT IS CLAIMED IS:

1. A method of calculating a static formation temperature in a reservoir penetrated by a wellbore; comprising:

estimating the static formation temperature;

calculating a formation fluid temperature at the wellbore using a three-dimensional fluid flow model through the reservoir, said calculation based, at least in part, on the estimated static formation temperature;

measuring the temperature of a sample of formation fluid at the wellbore;

comparing the calculated formation fluid temperature at the wellbore with the measured temperature of the sample of formation fluid; and

predicting the static formation temperature by altering the estimate of the static formation temperature until an error between the calculated formation fluid temperature at the wellbore and the measured formation fluid temperature is minimized.